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Multi-Mechanistic Approach to the Reservoir Analysis of Tight Blanket Sands

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ABSTRACT

Tight sa formations, because of their peculiar characteristics, do not conform to the well established behavioral patterns normally associated with conventional natural gas reservoirs. These attributes of tight sands render the conventional reservoir models inadequate when applied to tight sands. It is widely projected that gas resources available in these tight formations, which in the Western United States alone stands at about 5,703 Trillion Cubic Feet, may be the cornerstone of the future energy sufficiency of this country. It is also believed that the major bottleneck in the development of these resources .. the lack of understanding of the fluid dynamics in these formations. It is therefore imperative to evolve a good model based on a fundamental understanding of the rather unique physics of flow in this media. A very important unconventional characteristic of tight formations is its dual-porosity nature in the form of micro/macropore structure and the pressure-field, concentration-field driven flow potentials imposed on the system. This physics calls for the use of dual-porosity, multi-mechanistic approach for the description of the transport of natural gas in these formations. Such a model is presented here. Both synthetic and actual field examples are used to illustrate the predictive capability of the model. Results show that the conventional single-mechanistic approach tends to under-predict recovery. They also demonstrate that the dual-mechanistic approach is of the essence.

INTRODUCTION

The Western United States has an abundance of natural gas reserves in tight (low-permeability) formations. The current estimate of these reserves is approximately 5,703 Trillion Cubic Feet,[1] and a detailed resource study[2] for the Piceance basin estimates 420 Trillion Cubic Feet for that basin alone, thereby making tight gas a possible major contributor to the country's future energy needs. The development of this resource, however, has been limited, primarily because of an inadequate understanding of the fluid flow dynamics associated with tight formations. Without this understanding, future attempts at developing practical and economical exploitation technology will continue to yield inadequate levels of success.

References and illustrations at end of paper.

Tight gas sands, because of their peculiar characteristics, do not conform to the well established behavior patterns of conventional gas reservoirs, hence their classification as unconventional reservoirs. It is perceived that one important and peculiar characteristic of the tight formation is its dual-porosity nature, i.e., the existence of both macropores and micropores within the system. The micropores are believed to constitute the primary pore within the porous formation and, because of their molecular size, store the natural gas at the exclusion of the formation water. On the other hand, the macropores, i.e., the natural fracture network, are larger openings in which the formation water primarily resides. However, they also constitute the avenues through which the entrapped natural gas flows to the well in an unstimulated reservoir. Thus, the understanding of the fluid flow dynamics in both the micropores and macropores is an essential ingredient in the development of an overall picture of the producibility of these formations.

This micro/macropore structure calls for the use of a dual-porosity, multi-mechanistic approach for the description of natural gas transport in this type of porous media. This approach assumes that the natural gas flow in this type of formation is effected by two superimposed flow fields, namely a concentration gradient field and a pressure gradient field. While the first mechanism is a diffusion process, governed by Fick's law of diffusion, the latter is a Darcian mechanism. This method of gas transport is a two-step process whereby gas first flows as a result of a predominantly diffusion process from the micropores into the macropores. Then, the macropores serve as the primary flowing channels for the water and gas to flow towards the wellbore. Thus, while the flow in the micropores is considered single-phase, the transport problem in the macropores could initially be described as single-phase water flow but must soon revert to two-phase water/gas flow.

Available field data from the U.S. Department of Energy's Multiwell Experiment (MWX) provided the study area for this investigation.[3,4] Three wells, between 110 and 215 ft. at measured depth, have been drilled near Rifle, Colorado, through the Mesaverde formation. Two of the wells, MWX-1 and MWX-2, penetrate the Cozzette blanket sandstone, which is the primary focus of this study. The Cozzette formation is comprised of two parts, the Upper Cozzette and Lower Cozzette, both of which are uniform and continuous between the two wells. As a matter of choice and also because of the availability of production and well test data, the Upper Cozzette sand unit was chosen to illustrate the attributes of the multi-mechanistic approach when applied to tight formations.

Description of the Model

The basis for the mathematical formulation of this problem using the multi-mechanistic approach is defined by two potential fields, namely a pressure gradient field and a concentration gradient field. The basic premise is that the pore space in tight formations is comprised of a network of micropores and macropores. The micropores are said to be of molecular dimensions in diameter, whereas the macropores are much larger. It is further hypothesized that the micropores are accessible only to gas, whereas the water primarily resides in the macropores. When a pressure gradient is imposed upon this system due to the presence of a production well, then water would flow through the macropores (i.e., the natural fracture network) into the well. This process disturbs the previously existing hydrodynamic equilibrium between the gas dissolved in the water and the gas in the micropores creating localized concentration gradients. As a result of these localized concentration gradients, gas is driven into the macropores by Fickian diffusion. Hence, in time substantial quantities of both water and gas are produced at the well. This step-wise superposition of two flow fields upon one another generates an overall production mechanism which is referred to as multi-mechanistic flow regime.

As mentioned earlier, the formulation of a mathematical model to describe this multi-mechanistic flow entails the superposition of Fickian and Darcian flow. The details of this model and its applications have been well documented in earlier works by Sung and Ertekin[5] and Sung.[6] The equations governing the unsteady state flow of water and gas are presented below.

$$\nabla \cdot \left[D_g \left(\frac{S_g p_g}{z} \right) + 5.615 \, \frac{\lambda_g p_g}{z} \nabla p_g \right] + q_{ge} = \frac{\partial}{\partial t} \left[\frac{\phi S_g p_g}{z} \right] \tag{1}$$

and,

$$\nabla \cdot \left[\frac{\lambda_w}{B_w} \nabla p_w \right] + q_{we} = \frac{\partial}{\partial t} \left[\frac{\phi S_w}{B_w} \right] \tag{2}$$

The relationship between the phase pressures is defined by capillary pressure,

$$p_{cgw} \, (S_g) = p_g - p_w \tag{3}$$

which is a function of gas saturation,

$$S_g = 1.0 - S_w \tag{4}$$

The system of partial differential equations (Eq. 1 and 2) with the auxiliary relationships (Eq. 3 and 4) and the appropriate boundary conditions and initial condition define a well-posed problem. The resulting system of non- linear equations from finite difference approximations is linearized with the aid of a fully implicit generalized Newton-Raphson iteration procedure. Entries to the Jacobian matrix are supplied by numerical differentiation. Finally, the resulting system of equations is solved by using a direct solver equipped with a block-band algorithm.

Illustration of the Multi-Mechanistic Approach: Some Synthetic Examples

To illustrate the importance of the dual-mechanism approach for predicting the producibility of tight (low-permeability) formations, a series of simulations was conducted in which permeability was varied. The range of permeability values investigated is such that it is descriptive of both conventional and unconventional formations. The results of this study are depicted graphically in Figures 1 through 5.

Figure 1 is a plot of the ratio of gas production rate achieved using the dual-mechanism approach to that using the single-mechanism approach versus time. The results reveal that the contribution of the dual-mechanism approach is most pronounced for the lowest permeability system considered (k = 0.001 md). Moreover, at higher permeabilities (k ≥ 0.1 md), the predicted production advantage of the dual- mechanism approach over the single-mechanism approach is minimal. However, as the formation permeability is reduced to 0.01 md, the contribution from the Fickian flow component becomes prevalent, about twice the production prediction from the single-mechanism approach. This observation is even more dramatic for the 0.001 md system, in which the relative increase in production is more than 6 times. Furthermore, for permeability ranges normally encountered in conventional reservoirs (i.e., the 1 md system), the dual-mechanism approach offers practically no increase in production over the conventional single-mechanism approach.

Further comparisons on the dual- and single-mechanism approaches are provided in Figure 2. In this study, the ratio of cumulative production achieved using the dual-mechanism approach to that using the single-mechanism approach is plotted versus the logarithm of various values of permeability. The range of permeabilities for which the dual- mechanism approach is a major contributor to production, as well as that range for which it is not, is clearly visible.

Since the previous investigations are somewhat restricted in terms of time, thereby possibly concealing any benefits realized using the dual-mechanism approach, a series of simulations was performed for longer periods of time. For comparative purposes, the cumulative production realized using the single- and dual-mechanism approaches is plotted versus time. Also, as a production constraint, an abandonment flow rate of 30 MCF/DAY was assigned. As shown in Figure 3, the dual-mechanism contribution to overall production is most pronounced for the lowest permeability system considered. More importantly, however, is the fact that for the 0.001 md system, the single-mechanism approach predicts only 5 days of production, whereas the dual-mechanism approach predicts production for the full year, never realizing the abandonment flow rate of 30 MCF/DAY. Also, Figure 4 shows that during the early times of production in the 0.01 md system approximately 70% of the total flow is due to single-mechanism flow. This contribution of Darcian flow later stabilizes around 63%. Finally, as depicted in Figure 5, for the 1 md system the Fickian-flow mechanism contributes only slightly to overall production.

What these simulations illustrate is that for tight (low-permeability) formations, the single-mechanism approach definitely under-predicts production; the dual-mechanism approach is of the essence in order to accurately describe the production characteristics of these formations. Furthermore, for the permeabilities normally encountered in conventional reservoirs, the dual-mechanism approach has no significant application.

Application of Multi-Mechanistic Flow to the Upper Cozzette Sand

Necessary for the development and testing of the multi-mechanistic model, appropriate data must be first gathered and analyzed. Such data of interest, include permeability, porosity, in-situ water saturation, initial reservoir pressure, etc. These parameters, necessary for the accurate characterization of the Upper Cozzette blanket sand, are outlined in Table 1.[3,4,7]

Using this established set of reservoir and well parameters, a series of simulation runs were performed to "tune" the multi-mechanistic model (permeability being the "tuning" parameter) to actual production data from MWX-1, which was producing from the formation of interest, the Upper Cozzette blanket sand, during this time. Although it is well documented throughout the literature that this formation is highly anisotropic in permeability, the Cozzette was initially assumed to be isotropic and homogeneous. In this manner, the resulting "best-match" permeability is an effective permeability, making possible comparisons with previous investigators' work.[3] As shown in Figure 6, the "best-match" value of effective permeability was determined to be approximately 0.5 md, which is higher than that range suggested in an earlier work (0.2 - 0.3 md).[3]

The next step was to consider the known anisotropic nature of the system while once again attempting to history-match the actual production data. Various ratios of k_x/k_y which generate geometric mean permeabilities of 0.25 md were tested. As depicted in Figure 7, the "best-match" permeability contrast was determined to be $k_x/k_y = 10$, with $k_x = 0.8$ md and $k_y = 0.08$ md.

Considering the rather limited data that was used in the aforementioned model refinement procedure, it was decided to test these "tuned" permeability values by performing a series of simulation runs attempting to match actual interference test data of the Upper Cozzette formation. In these runs, the previously determined values of permeability were chosen as a starting point. Furthermore, since MWX-1 had been on production for some time prior to the interference testing, the reservoir pressure had dropped to approximately 6024 psi; thus, this pressure was used in lieu of the initial reservoir pressure as given in Table 1. Also, in order to accurately model the system's anisotropic permeability distribution,[4] the rectangular grid system used in these simulation runs (Figure 8) is such that the principal directions of permeability coincide with the axes of the coordinate system used. Since the actual interference test data consists of as many as 600 individual measurements in a single day, an exact simulation of the actual data was not considered. This problem was circumvented by averaging the data over a specific time interval. For "matching" purposes, MWX-1 flow rate was used as input data to the model, and the model's prediction of MWX-1 bottom-hole pressure was compared to the actual MWX-1 bottom-hole pressure.

As shown in Figure 9, the "best-match" permeability distribution was determined to be $k_x/k_y = 0.125$ md/0.01 md, which is equivalent to a geometric mean permeability of 0.035 md. This value of geometric mean permeability indicates that the dual-mechanism approach is applicable to this system. Using this permeability distribution, another simulation was conducted in which MWX-1 bottom-hole pressure was specified, thus effecting a match of the actual flow rate data and a check of the validity of the just determined permeability distribution. As shown in Figure 10, the flow rate match is consistent with the previous pressure match. Again using the "best-match" permeability distribution, a single-mechanism (i.e., Darcian flow only) simulation run was conducted to see if Fickian flow is indeed prevalent. The results, as shown in Figure 11, confirm the contribution of the Fickian flow, since the single-mechanism approach incorrectly predicts that the system would be depleted in approximately 11.8 days. Also of importance is the pressure response felt at the observation well, MWX-2. Figure 12 is a plot of both the simulated and actual MWX-2 bottom-hole pressure for the "best-match" permeability distribution, as determined by the dual-mechanism approach. There is good agreement between the actual and simulated data, thereby further confirming the "best-match" permeability distribution.

Knowing that the dual-mechanism "best-match" permeability distribution is not appropriate for a single-mechanism characterization of this formation, it was decided to once again match the actual data (MWX-1 BHP) neglecting Fickian flow. As shown in Figure 13, the "best-match" single- mechanism permeability distribution was determined to be $k_x/k_y = 0.14$ md/0.01 md, which yields a geometric mean permeability of 0.037 md. The purpose of this single-mechanism match is to generate a comparison between cumulative productions predicted using both the dual- and single-mechanism approaches with their respective "best-match" permeability distributions. In this manner, it can be shown that an "adjusted" single-mechanism approach (i.e., increasing permeability to account for the Fickian contribution to the production scheme) cannot accurately predict the productivity of low-permeability formations. The accurate representation of the physics using the multi- mechanistic approach is of the essence.

In order to bring into proper perspective the inadequacy of the strategy of adjusting permeability to match data, a series of simulation runs were conducted using the appropriate permeability distributions, thereby effecting a comparison of the predictive capabilities of the two approaches. The results of this study are depicted graphically in Figures 14 and 15 for two different sandface pressure specifications. The single-mechanism approach clearly under-predicts recovery, by approximately 275 MMCF over a 10 year producing period for the 14.7 psia specification case (Figure 14) and 200 MMCF for the 1000 psia case, even though the permeability distribution used had been "tuned" to match the interference test data.

CONCLUSIONS

It has been shown through a series of synthetic simulation runs that, for the range of permeabilities normally encountered in tight (low-permeability) formations, the multi-mechanistic approach is of the essence in order to accurately predict the producibility of these types of formations. Conventional simulators definitely under-predict recovery. Also, results have been presented from the investigation of an actual low-permeability formation, the Cozzette blanket sand. In this study, two approximate permeability distributions were determined, one for the single-mechanism approach and one for the dual-mechanism approach, by matching actual interference test data. The two models were then ran for an extended period of time (10 years) in order to effect a comparison of their respective predicted cumulative recoveries. The results reveal that the single-mechanism approach under-predicts recovery by as much as 275 MMCF, even though its permeability distribution was adjusted to account for Fickian flow. Clearly, an appropriate description of the fluid flow physics, as provided by the dual-mechanism approach, is necessary for an accurate characterization of the productive capacity of tight formations.

NOMENCLATURE

B_w	=	Water formation volume factor	bbl/STB
D_g	=	Micropore diffusion coefficent	ft^2/day
k	=	Permeability	md
p_g	=	Gas phase pressure	psia
p_w	=	Water phase pressure	psia
p_{cgw}	=	Capillary pressure between gas and water phases	psia
S_g	=	Gas saturation	fraction
S_w	=	Water saturation	fraction
q_{gt}	=	Gas flow rate	SCF/day

q_{wt}	=	Water flow rate	STB/day
z	=	Gas super compressibility factor	fraction
λ_g	=	Gas mobility	md/cp
λ_w	=	Water mobility	md/cp
$\nabla\cdot$	=	Divergence operator	
∇	=	Gradient operator	

ACKNOWLEDGEMENT

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TABLE 1

Reservoir and Well Parameters for the Upper Cozzette Blanket Sand

Formation height, ft	30
Formation porsity, fraction	0.069
Formation water saturation, fraction	0.40
Reservoir temperature, °F	230
Gas viscosity, cp	0.018
Initial reservoir pressure, psia	6300
Critical water saturation, fraction	0.25
Critical gas saturation, fraction	0.0
Relative permeability to gas at S_{wc}, fraction	1.0
Relative permeability to water at S_{gc}, fraction	1.0
Wellbore radius, in	3.5
Depth of formation, ft	7855
Relative permeability relationships:	Corey's Model
Formation permeability, md	"Tuning Parameter"

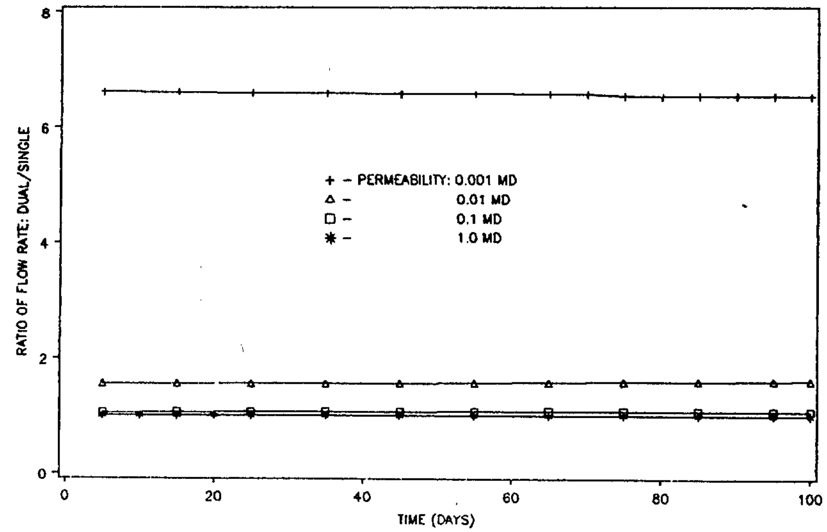

Fig. 1-Comparison of single- and dual-mechanism approaches via ratios of flow rates achieved (p_{wf} = 14.7 psia).

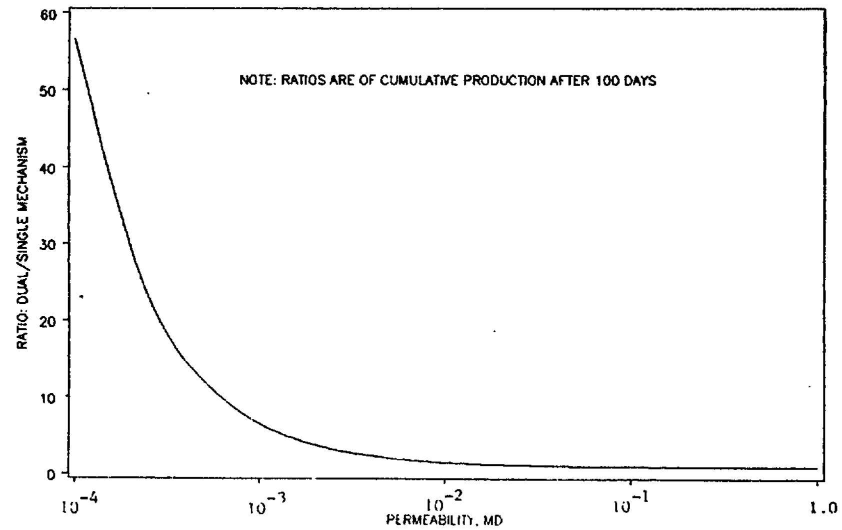

Fig. 2-Comparison of single and dual-mechanism approaches via ratio of cumulative production achieved (p_{wf} 14.7 psia).

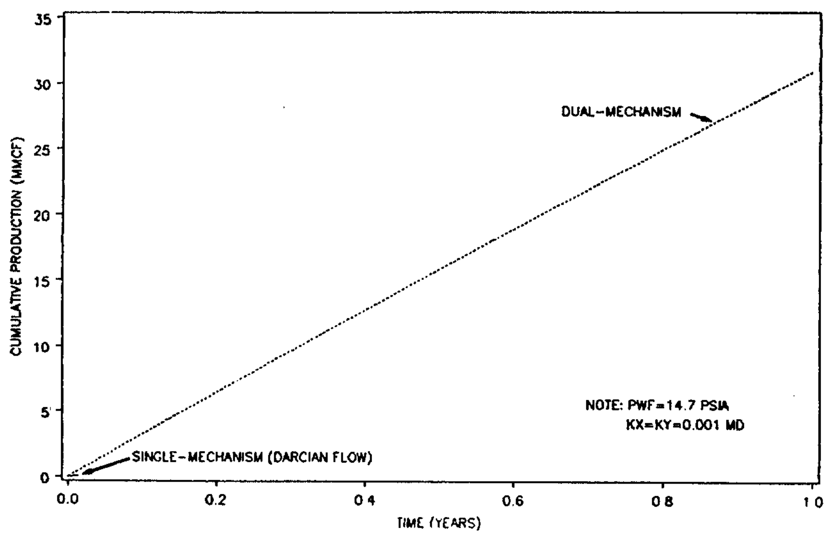

Fig. 3-Comparison of cumulative production, single- vs. dual-mechanism, after 1 year (k = 0.001 md).

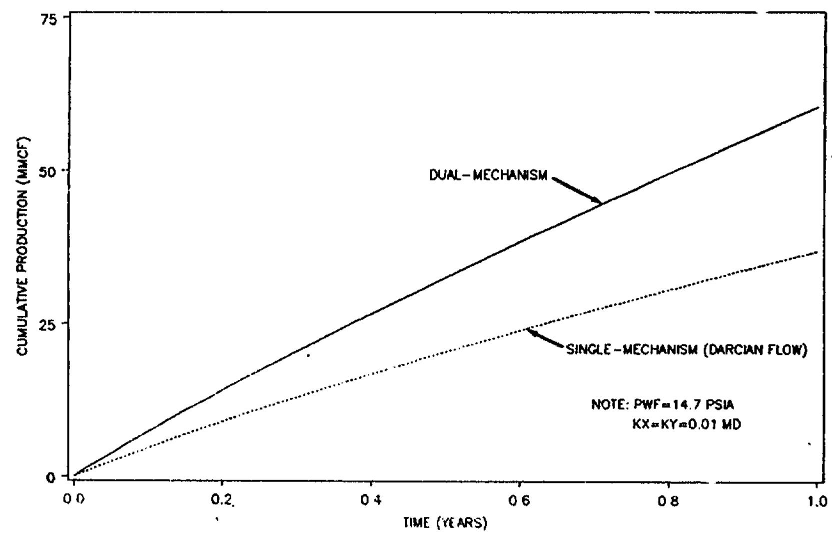

Fig. 4-Comparison of cumulative production, single- vs. dual-mechanism, after 1 year (k = 0.01 md).

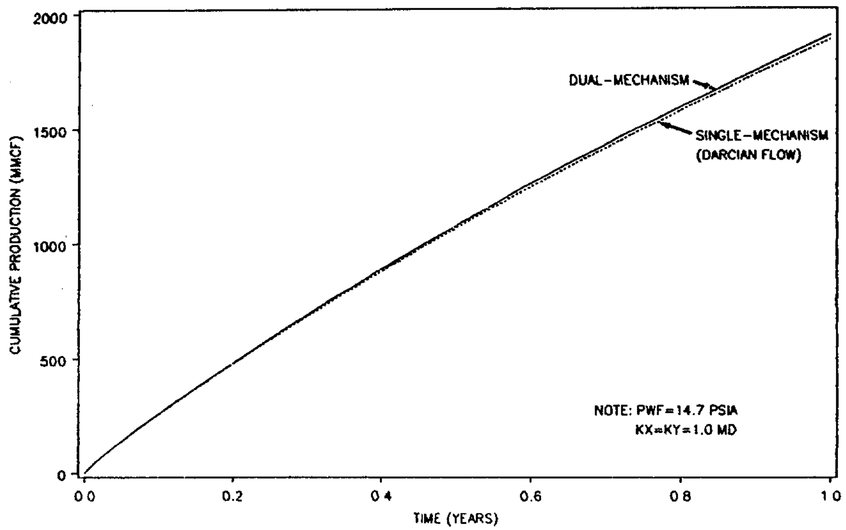

Fig. 5-Comparison of cumulative production, single- vs. dual-mechanism, after 1 year (k = 1.0 md).

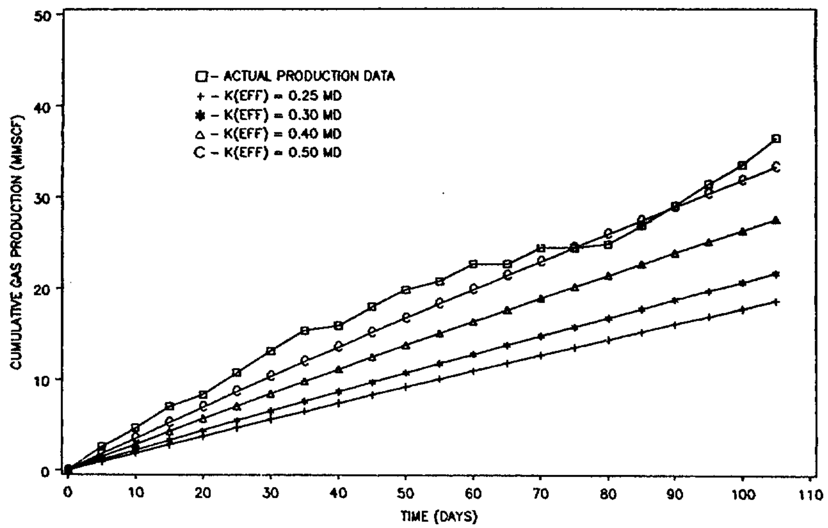

Fig. 6-History matching of the Upper Cozzette production data by varying the effective permeability to gas (p_{wf} = 4200 psia during the production period).

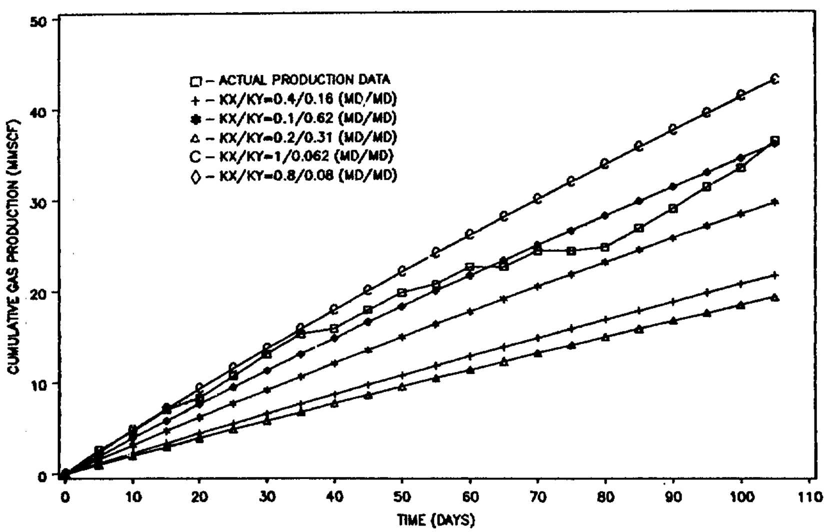

Fig. 7-History matching of the Upper Cozzette production data by varying the permeability contrast (p_{wf} = 4200 psi during the production period).

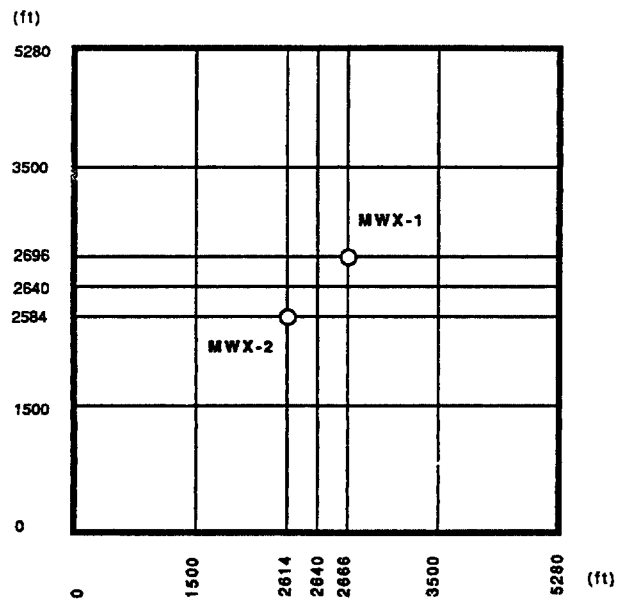

Fig. 8-Grid system used to simulate the interference testing of the Upper Cozzette blanket sand at the DOE MWX site.

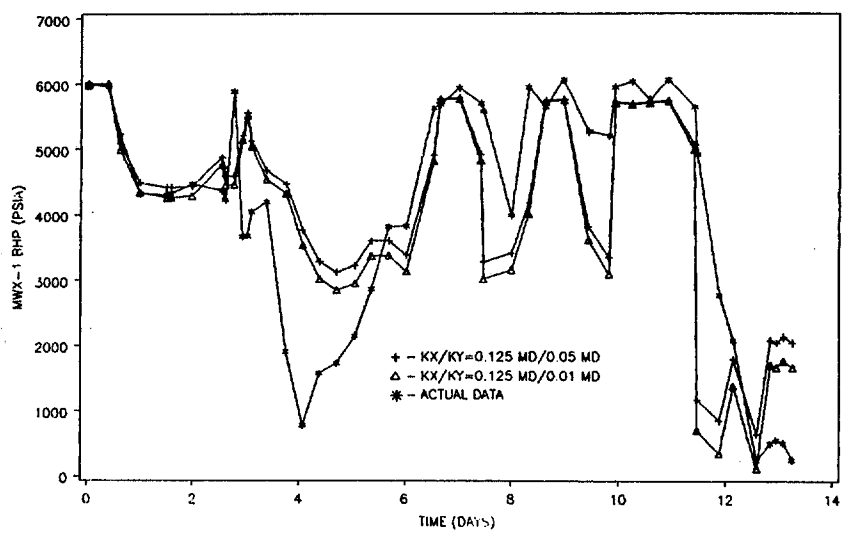

Fig. 9-History matching of the Upper Cozzette interference test data using dual-mechanism approach.

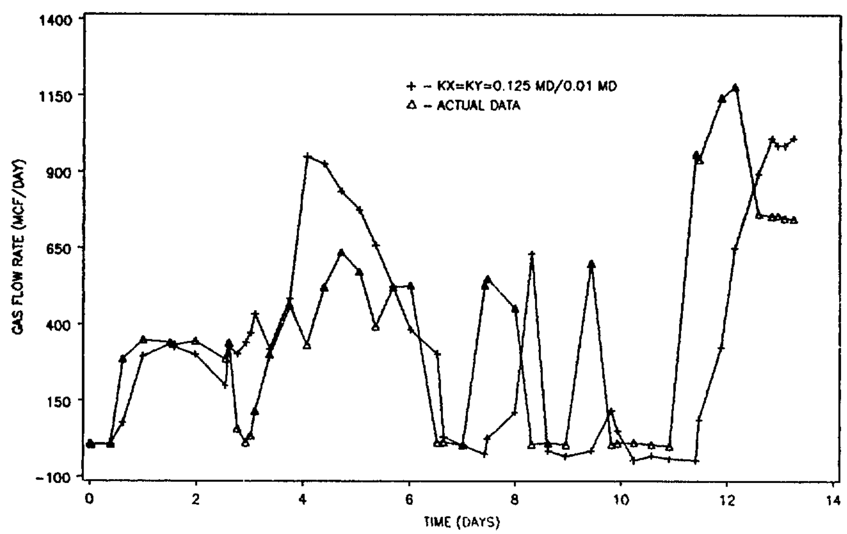

Fig. 10-Simulated flow rates achieved using the "best-match" permeability distribution and actual flow rates.

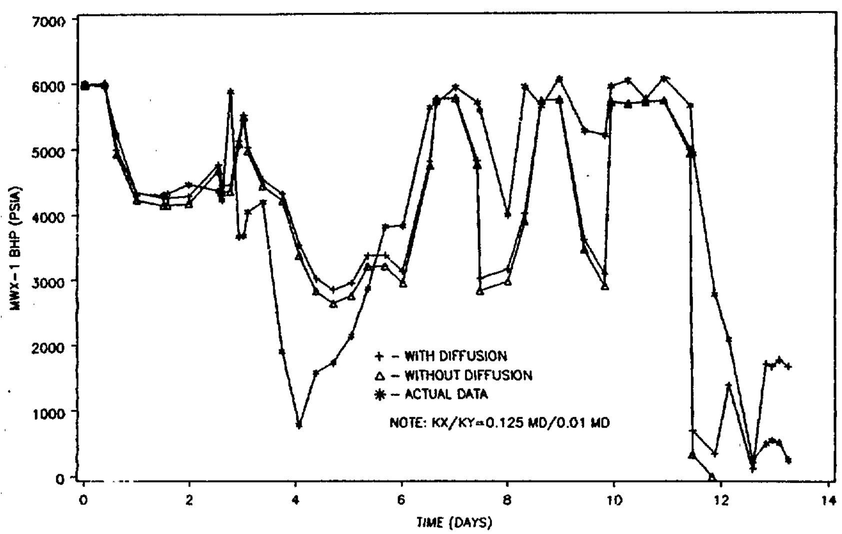

Fig. 11-Effect of Fickian flow contribution on the model's ability to match interference test data.

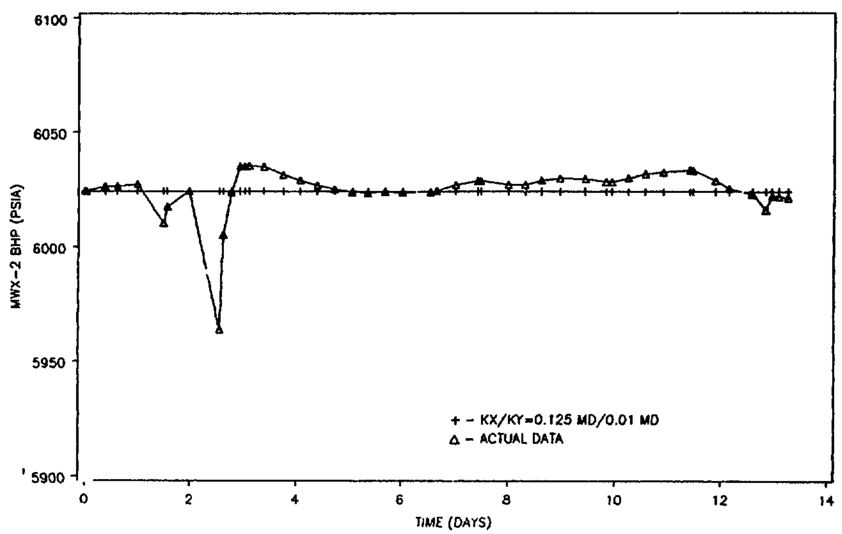

Fig. 12-Comparison of simulated and actual pressure responses at the observation well, MWX-2.

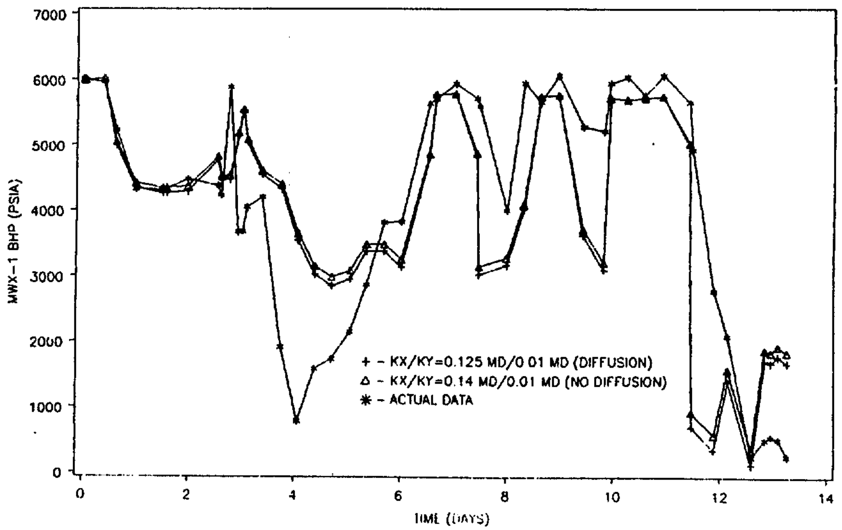

Fig. 13-History matching of the Upper Cozzette interference test data using single-mechanism approach.

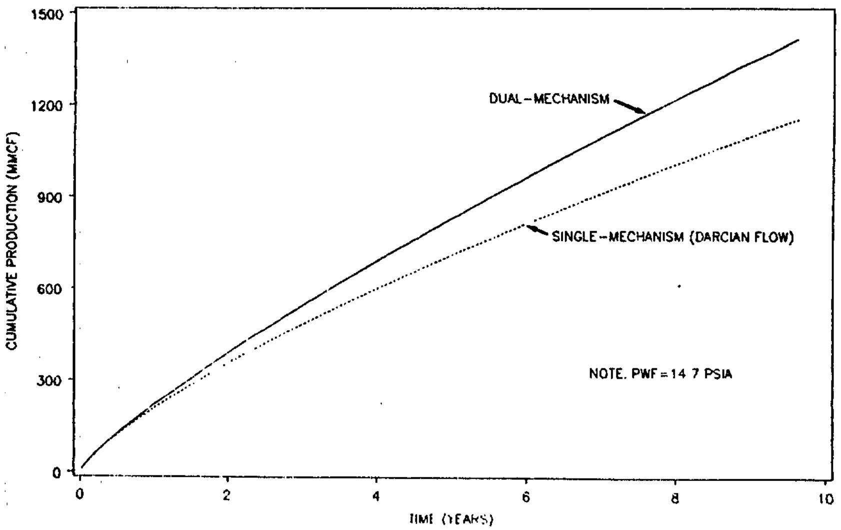

Fig. 14-Prediction of cumulative production by single- and dual-mechanism approaches (p_{wf} = 14.7 psia).

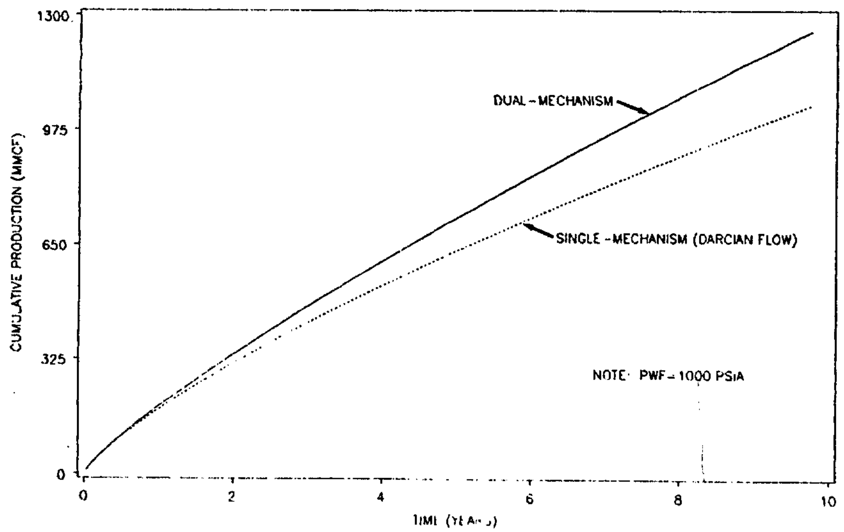

Fig. 15-Prediction of cumulative production by single- and dual-mechanism approaches (p_{wf} = 1000 psia).